COMMENTS ON BEHALF OF

THE CITIZENS ACTION COALITION OF INDIANA
AND
HOOSIER ENVIRONMENTAL COUNCIL

RELATING TO THE DISTRIBUTED RESOURCE RULEMAKING

BEFORE

THE INDIANA UTILITY REGULATORY COMMISSION

March 1, 2002

On January 25, 2002, the Commission by open letter initiated a preliminary discussion on the topic of distributed resources in Indiana. In a white paper issued at the same time by the Commission, it stated that the discussion was an outgrowth of the Commission's Reliability Proceeding (Cause No. 41736) and that the Commission intended the discussion to result in a comprehensive agency rulemaking in order to implement incentives whereby the value of distributed generation to individual customers and the utility are adequately reflected to each. The Citizens Action Coalition of Indiana supports the Commission's goals and submits the following comments in response to the Commission's request.

OVERVIEW

I. The Benefits of and need for Distributed Resources

The concept of Distributed Resources (DR) includes both demand-side and supply-side measures to generate or save electricity which are *distributed* throughout the electricity network. In other words, DR encompasses the large number and variety of electricity-generating *and* electricity-saving measures that are located at or on the customers premises or are close to customers and load centers.[1] The benefits in terms of reliability and end-use customer savings contributed by supply-side and demand-side resources are often very similar.[2] In addition, the hurdles with regard to interconnection and existing rate structures and price incentives confronting both supply-side and demand-side distributed resources are also often very similar. Because of this similarity in both benefits of and obstacles to demand-side and supply-side DR, any discussion of distributed resources should address both demand-side and supply-side DR alternatives.

DR provides both direct benefits and indirect benefits to end-user customers and the distribution utility by reducing system energy usage, improving energy consistency, enhancing network reliability and deferring costly capital and infrastructure improvements. Direct end-user benefits would include lowering an individual customer's bill by decreasing energy usage through installing an efficiency measure or by providing for lower cost or more reliable energy to a specific customer location. The benefits of distributed generation, however, go far beyond the more obvious direct end-user benefits.

Because of their size and the fact they are distributed throughout the network, DR creates a whole host of benefits in terms of increased network reliability, decreased distribution and transmission costs, energy savings through market efficiency, savings through deferred network investment, and improved long term resource planning. Properly implemented DR can also achieve significant environmental benefits.

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[1] Richard Cowart, *Distributed Resources and Electric System Reliability* 5 (The Regulatory Assistance Project, September 2001).

[2] *Id.*

There is currently a need for increasing network reliability which DR can help achieve. Between 1993 and 1997 the United States experienced noncoincident summer peak load growth of over 56,000 MW and many estimates predict that every one of the nation's 10 regional reliability councils will experience shortages in the next 5 to 7 years.[3] The underlying cause in a number of the most significant power problem events of 1999 was the high loads the electric system was required to serve at the time of failure.[4] DR can improve power quality, ensuring consistent power to stressed areas or power quality sensitive operations. DR can also relieve distribution overloads and transmission congestion as well as ensure adequacy by closer matching generation and load. In other words, DR can help solve network reliability problems.

DR can also reduce distribution and transmission costs – benefits which have been masked in part by the averaging of distribution and transmission costs. Although average distribution rates in the United States may be approximately 2.5¢ per kWh, they can vary dramatically from one location to another and marginal distribution system costs may vary from zero to over 20¢ per kWh.[5] This wide variance results from the differences in underlying cost between serving areas of low growth and high excess capacity and areas of high growth and constrained capacity.[6] Deploying distributed resources in high distribution cost areas not only

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[3]*Id.*, at 4.

[4]*Id*. (citing US DOE, *Report of the US Department of Energy's Power Outage Study Team* (March 2000 Final Report), at S-2).

[5]David Moskovitz, *Distributed Resource Distribution Credit Pilot Programs: Revealing the Value to Consumers and Vendors 5*, The Regulatory Assistance Project (September 2001).

[6]*Id.at* 6.

improves network reliability but also helps defer the need for expensive network upgrades. In addition, including DR can make network planning and investment more cost effective.

Properly implemented DR improves market efficiency and long term planning. Historically, loads were generally free to consume electricity on their own schedule to meet the customers' needs while the system operator controlled generation in order to balance the system.

Alternatively, both demand and supply-side DR, such as load management and generation, can also be used to balance the system. Studies have shown that between 15% and 17% of load can be managed in response to price signals.[7] With proper rate structures that provide price information and incentives, both supply and demand-side distributed resources can be utilized to shave energy demand peaks and relieve constraints on generation, transmission and distribution facilities. In so doing, distributed resources improve competition and efficiency in the marketplace, lowering spikes in electricity wholesale spot markets and leading to greater price stability and better long term planning.

Distributed resources can also provide significant environmental benefits. Demand-side distributed resources, such as efficiency and load reduction, reduce the need for generation and therefore reduce associated air and other emissions. However, even supply-side distributed resources can provide benefits. Many of the technologies used for supply-side distributed resources, such as natural gas fired micro-turbines, photovoltaic arrays, wind-power conversion, and fuel cells have little or no environmental emissions. Unfortunately, some supply-side distributed resources include diesel or other fossil-fuel generation units which not only have emissions but often do not even meet the environmental requirements placed on traditional generation facilities.

II. **<u>Because there are differences among the types and technologies of distributed resource measures, different rate or certification treatments are needed depending on the size, technology, or customer class.</u>**

As discussed above, the measures that can be called distributed resources can differ dramatically is size, technology, cost, utilization and impact on the electric network. These differences require that different measures receive different treatment with regard to rates, certification, planning requirements, etc. However, distributed resources need to be treated in the same manner as customer loads are treated and broad aggregate customer uses should be treated the same.[8] In other words, rate design and levels, measure siting and approval, and other considerations should be based on the technology or the application (and its impact on the network). For large applications, such as a 10 to 30 MW generator, the process should be streamlined compared to what is required for a 250 MW merchant plant. For smaller applications, such as those below 100kW, rates and certification should <u>not</u> be on a customer by customer basis.

Rates and certification for the smaller distributed resources should be based on aggregate performance or value. Just as it would be impractical to meter and try to predict the load curve of individual water heaters in every home in a community it would be impractical to individually deal with small distributed resource measures such as a fuel cells or photovoltaic panels

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[7]Cowart, at 20.

[8]Moskovitz at 10.

distributed throughout the community. Requiring customer by customer treatment only perpetuates regulatory burdens on deployment of distributed resources.

However, by dealing with measures in the aggregate by the type of application, the process can be streamlined and additional technical problems can be resolved. For example, if the Commission develops uniform standards based on the type of application (for example one set of standards for fuel cell of a particular size or for 10 kW photovoltaic panel, including required safety mechanisms and electronic interfaces) the Commission ensures that the measures installed will not create problems for the electric network and will improve aggregate predictability.

The Commission should therefore develop rules based on the size of the measure. For example, new units or additions at or below 20 MW would have rules allowing for a detailed but expedited approval process. Rules for units below 2 MW would be further streamlined, and units below 250 kW would be even further streamlined with certain approvals and certifications waived as long as the technology used complied with certain pre-established standards. Because such small loads would be incremental, they would individually have only an incremental impact on the network. The Commission could create a review process to look at the aggregate effects and revise the generic standards as needed.

Because many distributed resources will be dedicated at least in part to on-site load, the Commission should develop rules to distinguish between the portion of resources used on-site and the portion used for net-export.

In addition to distinguishing between measures based on size and application, rather than on a customer by customer basis, the Commission should be careful to distinguish between environmentally beneficial distributed resources and those that are not. However, all supply-side resources should be required to comply at a minimum with the same air and water quality standards as applied to traditional new source generation stations.

The Commission should also require utilities to do distribution system planning and reporting of potential reliability problems (discussed in more detail below). DR should be included in the Integrated Resource Plan (IRP) of utilities and the Commission should develop rules and requirements for an RFP process and allowing third parties to bid for DR projects to improve system reliability.

Responses to question posed in the IURC Staff white paper

a. Please provide a definition of distributed generation, including engineering characteristics and unit size. Should the definition differ depending on customer class?

Distributed resources encompass the large number and variety of electricity-generating *and* electricity-saving measures that are located at or on the customers premises - that is, measures to generate or save electricity that are distributed throughout the network, close to customers and load centers.[9] It is important to note that the benefits in terms of reliability and end-use customer savings contributed by supply-side and demand-side resources are often very similar.[10] In addition, supply side and demand-side distributed resources often face similar

[9] Richard Cowart, *Distributed Resources and Electric System Reliability* 5 (The Regulatory Assistance Project, September 2001).

[10] *Id.*

hurdles with regard to interconnection and existing rate structures and price incentives. Therefore, any discussion of distributed resources should encompass both the supply side and demand side alternatives.

No standard definition for the size of distributed resources currently exists. Generally the upward limit for defining a distributed resource is 10 MW, but some customer owned generation may be as large as 100 MW.[11] A distributed resource may be owned by an end-use customer, the distribution utility, or some third party such as an ESCO or an independent power producer. It may be controlled by the customer or by some other party and it may be located on the customer's property on either side of the meter or not on the customers property at all but elsewhere in the community on the lower-voltage system.[12] It may be an individual measure controlled by an individual such as a photovoltaic panel or a fuel cell, or it may consist of an array of measures such as controlled air-conditioning cycling centrally dispatched by an ESCO or distribution utility. With regard to supply-side options, a customer may use all or only part of the energy the distributed resource generates. What makes a resource a distributed one is not its technology or its size, but its relation to the electricity network – it is distributed throughout the network, close to customers and load centers.

This does not mean that the Commission's rules should be technology oblivious. For example, diesel powered DR measures might provide some short term reliability benefits in load pockets but would not necessarily be the economic choice and certainly would lead to increased

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[11] *Id.*

[12] *Id.*

environmental problems. Not all DR technology is equal and technology that offsets the benefits of DR with environmental degradation should be discouraged.

b. <u>Assuming net metering as the first step in a DG rulemaking, what are the benefits for customers with net metering and what are the possible negative effects?</u>

Under net metering, if a customer resource (usually under 15 kW) generates more electricity than the customer can use during the time the electricity is generated, the excess goes through the electric meter and into the grid, spinning the meter backward. The meter shows only the net amount, measured as the difference between the electricity generated and the electricity purchased from the utility. This benefits both the customer and the utility.

First, it is a simple way for consumers to get full the value of the electricity they generate. For example, when a residential customer installs a supply-side distributed resource, such as a photovoltaic panel or wind-power conversion system, they may not be home when the system generates electricity. Rather than investing in expensive battery units to store the electricity they generate, net metering allows the customer to "store" the excess electricity on the grid. This reduces or offsets the electricity they would otherwise have to purchase when their system is not generating enough energy to meet their needs. In other words, net metering allows customers to use the full amount, and get the full value, of electricity they have generated first, before buying electricity generated by their utility.

In the absence of net metering, small customer-generators would usually have two meters, one for measuring incoming electricity, for which they pay the retail rate, and one for measuring the power they produce, for which they are compensated at some other rate (usually the utility's avoided cost). Thus, net metering provides an economic incentive for electricity customers to install on-site, small-scale, renewable generating capacity.

Net metering may have some impact on utility revenues due to reduced power sales and because it may not allow full recovery of average distribution costs. However, the US DOE claims a number of studies show that net metering can benefit utilities.

Utilities benefit from net metering by avoiding the administrative and accounting costs of additional metering and purchasing the small amounts of excess electricity produced by supply-side distributed resources. Net metering helps promote distributed resources which can help avoid the need for additional power generation, and investments in distribution network upgrades. In addition, grid-connected photovoltaic systems, for example, can produce power at peak, when utility generation costs are higher and they often need the extra power.

c. <u>What kind of tariff structure can be used to deal with different amounts and sizes of DG and still make net metering practical?</u>

Net metering is premised on economically balancing the electricity a customer generates against the amount the customer consumes. Different classes of customers will generally have different loads and will utilize different size resources. In addition, some customers will be net-consumers of electricity and other may be net-exporters. The rules need to reflect these differences.

A customer that is a net user of electricity should get the full value of the electricity they self-generate. This is especially true for small DG applications where dispatch is not easily controlled, such as residential photovoltaic or wind power conversion applications. The cost of separate meters or time of use meters, administrative costs, and other considerations make straight net metering the most practical consideration for these applications. Larger applications, say of 20 MW and up, however, may need special consideration. Customers installing DG of that capacity are likely to be more able to precisely match generation with consumption – either through increased dispatch and/or load control and through proper sizing of generation capacity.

If a customer is a net generator or net exporter of electricity, the net exports should receive the same treatment as energy produced by a third party distributed resource generator participating in the wholesale market. This is especially true of larger DG applications or applications that are sized in excess of load. In order to get the full benefits of distributed resources, owners of DG in excess of their load should be able to respond to price signals in the market – either through curtailing load or supplying generation at market rates. Both supply-side and demand-side DR can be used to balance the system and it is important that rate mechanisms recognize this function and allow full participation on an even playing field in energy markets.

Another option to consider is designing rates to track seasonal loads and peaks in order to better track the marginal cost of power. Although hour-by-hour time of use metering is impractical for most small customers, seasonal rates have been used in other jurisdictions in order to encourage customer load management.

d. <u>How should a utility determine the fixed amount of cost per customer with net metering, for both a net buyer and/or net seller?</u>

Because marginal costs of distribution can vary dramatically depending on the age and capacity of the facilities as well as current load and load growth, utilities may in fact need to be required to credit customers deploying distributed resources rather than charging them.

The only way to determine whether a customer should pay a charge or receive a credit, or determine how much that credit or charge should be, is for each distribution utility to do a detailed cost study of the distribution network. That study should look at current distribution facilities, including substations, current load and load growth. It should be system wide and not be customer specific although individual customers with large loads will certainly need to be taken into consideration. Utilities should be required to file and periodically update a list of all major (greater than $1 million) distribution upgrades because those are likely to be where the highest costs are.[13] Each utility should also state what load reduction would allow those expenses to be deferred. In addition, the Commission should require distribution utilities to file and periodically update the list of areas, by feeder and substation, that have the worst reliability record in terms of outages.[14] These areas may be good candidates for using distributed resources to improve reliability.

Any charge or credit needs to take into consideration the scale of the various distributed resource measures and whether the resource owner is a net buyer or net seller. In areas where the distribution network is stressed or constrained the utility should provide distribution credits that provide an incentive for deployment of distributed resources while generating savings from more efficient distribution system and planning for the utility – savings which should be shared with its customers. Distribution credits should be available to both supply-side and demand-side DR and areas of distribution system constraint or stress should be targeted with those credits as part of long term distribution system planning.

The value to the distribution network of distributed resources can be determined by looking at what the distribution system's marginal costs are and the extent to which the distributed resources in the aggregate will lower or defer those costs. The Regulatory Assistance Project has two reports that specifically address those issues – *Costing Methodology for Electric*

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[13]Moskovitz at 10.

[14]Moskovitz at 10.

Distribution System Planning, November 9, 2000, and *Distribution System Cost Methodologies for Distributed Generation* (RAP, 2001).[15]

e. <u>How do tariffs need to be designed to adequately reflect the efficient recovery of the fixed and variable costs for service to customers that operate DG equipment using a net meter?</u>

Tariffs need to be designed to reflect not only the fixed and variable costs to the utility of distributed resources, but also the benefits and savings to the utility. Small applications, such as wind-power conversion, photovoltaic applications, residential fuel cells and efficiency measures need to be viewed in the aggregate. Any recovery of fixed and variable costs needs to include offsets relating back to benefits from improved reliability and reduced future distribution network investments.

Because distributed resources can be used as a substitute for distribution investment, it is important that the Commission develop an appropriate mechanism to compare costs. Analysis shows that distribution costs can be thought of as a "mountain of cash."[16] Huge savings can be realized with the proper cost analysis, rate structures and incentive mechanisms. The Commission should require distribution utilities to perform distribution cost studies to determine where the system experiences high costs. Distributed resources can then be targeted to those areas.

f. <u>How can stranded costs be identified and measured?</u>

It is questionable whether concept of stranded costs even applies with regard to

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[15] Available at "http://www.rapmaine.org/DistributionCostStudyFinal.PDF"(Last viewed February 28, 2002).

[16] Moskovitz at 9.

distributed resources. So-called stranded costs, when they occur, result from major changes in market dynamics due to fundamental changes in government policy and regulation. Examples of such fundamental policy shifts include FERC Order 888 and electric industry restructuring laws. Order 888 and its progeny already resolve stranded cost issues as they relate to the wholesale generation and transmission markets. Indiana has not enacted electric industry restructuring or customer choice legislation.

Utility sponsored DR should be part of long term planning and designed to (and only required when) it provides net benefits to the system. In contrast, end user distributed generation will only result when it passes the owners benefit test. It may not pass the traditional system benefits test and it should not be required to do so. After all, it is the end user and not the utility making the investment in distributed generation resources in that instance.

Only when DR creates a net loss in current generation revenues for a utility should generation costs figure into any utility's stranded cost calculation. If the utility continues to experience load growth in the face of distributed resources, it has not lost generation revenues but has only gained new revenues at a slower pace and therefore should not be able to claim any stranded generation costs.

With regard to stranded distribution system costs that might conceivably result from DR, if they actually occurred, could only be identified after detailed distribution and load growth studies are completed. Those studies should not be customer specific but based on a systemwide analysis with enough granularity to identify any existing load and distribution system constraints. Small distributed resources will individually impact the utility on an incremental basis and can provide reliability benefits to the system. Such resources should be viewed in the aggregate and not on a project by project basis.

Furthermore, DR creates significant savings, reliability, and environmental impact benefits. Those benefits must be fully accounted for and included in any analysis to determine whether stranded costs might exist.

g. <u>What, if any, are the benefits and revenues that should be considered as offsets to stranded costs?</u>

First, it is questionable whether the concept of stranded costs even applies to DR. If it does, however, there are a number of benefits and revenues to be included as offsets to stranded costs.

Distributed resources located in load pockets or where transmission and distribution systems are strained, and therefore costs are high, actually reduce costs and should be considered in offsetting stranded costs. The benefits from using distributed resources to balance the system, especially when demand is high and distributed resources allow the utility to avoid expensive purchased power or new generation need to be considered.

h. <u>What rate design alternatives would reduce the potential for any stranded costs?</u>

Stranded costs ought not be the primary or even a significant factor in rate design with regard to DR. In fact, it is questionable whether concept of stranded costs even applies with regard to distributed resources.

i. <u>Should standby rates for backup power be used, and if so under what criteria?</u>

Standby rates should only be used for large distributed generation facilities where the consumer can control dispatch of its facilities and intends to use the resource to fulfill a significant part of its needs. Standby rates are inappropriate for small net metering applications such as residential wind power or photovoltaic applications.

j. <u>What different kinds of standby services do customers with DG require and can the utility reasonably supply?</u>

Whether a customer with distributed generation will require standby services will be a function of the customers needs, the size of the load, the size of the resource, and cost factors. In the case of large distributed resources or large customer self-generators, standby services may be able to be cost-effectively contracted for on a bilateral basis. For small units that can be owner dispatched, such as a fuel cell, it would be impracticable for each fuel cell owner to negotiate standby services on an individual basis. A set of generic standby services and corresponding tariffs should be developed, and those services need to take into account differences in customer size and how well self-generation matches the load.

k. <u>In order to determine the necessity and proper design of standby rates we need further information on distribution system design, operations, and cost structure. Please provide any information that might help to develop efficient standby rates.</u>

The Citizens Action Coalition does not possess sufficient information to respond to this question at this time but reserves the right to provide a response in the future.

l. <u>Are there areas in Indiana with distribution constraints?</u>

The Coalition has no information regarding any current specific distribution constraints but it is probable that some do exist in Indiana. The only way to find out for sure is to require distribution utilities to file distribution system reports. Those studies should look at current distribution facilities, including feeders, substations, current load and load growth. They should be system wide and not be customer specific although individual customers with large loads may need to be taken into consideration. The Commission should require utilities to file and periodically update a list of all major (greater than $1 million) distribution upgrades because those are likely to be where the highest costs are.[17] Each utility should also state what load reduction would allow those expenses to be deferred. In addition, the Commission should require distribution utilities to file and periodically update the list of areas, by feeder line and substation, that have the worst reliability record in terms of outages.[18] These areas may be good candidates for using distributed resources to improve reliability.

The Commission should also establish an RFP process to allow parties other than the distribution company to bid for providing DR measures to relieve potential distribution system constraints. The process should be open to end-use customers, independent energy service companies, other third party entities, and even other utilities. An open bidding and RFP process would help ensure that distribution system reliability is maintained and enhanced in the most cost-effective manner.

m. <u>Should utilities be required to file a location-specific set of T&D costs?</u>

The Commission should require utilities to file and periodically update system wide distribution costs studies by feeder line and substation and which identify planned major distribution network upgrades of more than $1 million and areas that have the worst reliability. Small distributed resources, e.g., up to 110 kW, should be treated in the aggregate and distribution system studies for such small applications on an individual basis are not necessary or efficient. Distribution studies for large projects, e.g., between 2 MW and 20 MW, may need site specific distribution studies but the Commission should develop an expedited process by which

[17] Moskovitz at 10.

[18] *Id.*

those studies are done. Medium-size applications may, in some instances, need a site specific review, which should be streamlined. It may be possible to design a review process that only triggers a site specific review of medium-sized projects based on "red flags" in the utilities' overall distribution system reports. The Commission should develop rules that allow such information to be used in an RFP/bidding process in order to promote cost-effective measures to relieve constraints on the distribution system.

n. <u>What constitutes an economically efficient buy-back rate?</u>

Buy-back rates need to take into consideration the market price for electric energy, and the costs *and* savings to the distribution and transmission facilities created by distributed resources. Because many environmentally friendly generator technologies are suitable for DR use, buy-back rates should also take into account environmental benefits. In addition, it makes sense to distinguish between small DR applications (under 10 kW) and medium-sized and large DR applications. As discussed above, net-metering is the appropriate method for buy-back rates for small DR applications where the customer will be a net-consumer of power from the electric grid. In medium-sized and large applications where the resource is owner dispatchable and where the owner is a net-exporter of power onto the grid, buy back rates should take into account the market price of power and the benefits to the system created by the DR.

o. <u>What information should be included in a utility standard application form for distributed generation?</u>

The standard application form for distributed generation should vary with the size of the project and the nature of the project. At a minimum, the application should contain information about the applicant, the installer, and the technical aspects of the technology being deployed. The Commission should develop generic standards and an expedited application process for small projects such as Vermont has done.[19]

p. <u>What costs are incurred by a utility to review a DG project?</u>

The costs incurred will vary depending on project size, location, and advance planning by the utility. If the Commission adopts the distribution system reporting and planning procedures discussed above, there will be *de minimus* administrative costs for small projects.

q. <u>Do these costs vary for different DG project proposals?</u>

Yes, the costs a utility incurs to review DG projects will vary with the size of the project and its location within the distribution system. If the Commission requires the distribution studies recommended above, those costs will be minimal for small projects, which should be treated in the aggregate and not on a customer by customer or project by project basis. In addition, it will be possible to streamline review of medium sized projects and expedite larger projects.

r. <u>How long should it take a utility to evaluate a project?</u>

The length of time it takes a utility to review a project will vary with the size of the project and the Commissions rules for such reviews. If the Commission adopts the distribution system reporting requirements discussed above and develops generic standards for distributed resource projects, such projects become virtually pre-certified, allowing the projects to be implemented by simply filing the proper application. In addition, medium and large size projects would take less time than otherwise because the utility will already have much of the distribution

[19] Vermont net metering standards and application. Technical interconnection standards available at http://www.state.vt.us/psd/ee/interconnection.PDF. Application available at http://www.state.vt.us/ psb/ download/5100_new_form.PDF

system planning done.

s. <u>What are the criteria a utility should use to evaluate a DG project?</u>

The criteria a utility should use to evaluate a DG project will vary depending on whether the project is being supported or promoted by the utility as part of its long term planning or whether the project is being developed by an end-use customer or third party in response to market conditions and customer needs. The criteria for customer or third party projects will vary by the scope of the project.

Distribution utilities should, as a matter of prudent long term planning, consider DR applications as part of the mix of options available to meet customer demand, balance and manage system load, ensure and improve reliability, and comply with environmental regulations. In such situations the utility should consider distribution and transmission constraints, the cost of new large central dispatch generation, market prices for power, tougher air quality standards and compliance costs, and the cost effectiveness of the measure.

Developing of distributed resources by end-use customers or third parties is primarily at the discretion of the party choosing to develop them. The utility must have a review process to ensure integrity of the network can be maintained. It should not, however, be allowed to use that review process to stymie or delay development by end-use customers or other parties. The utility should comply with the reporting and filing requirements discussed above and should expedite review of proposed projects. For small projects that review should be no more than the resource developer has complied with the standards and application process established by the Commission.